UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2005

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number 1-10934

ENBRIDGE ENERGY PARTNERS, L.P.
(Exact name of registrant as specified in its charter)

Delaware	**39-1715850**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1100 Louisiana
Suite 3300
Houston, TX 77002
(Address of principal executive offices and zip code)

(713) 821-2000
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by checkmark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes ☒ No ☐

The Registrant had 46,802,634 Class A common units outstanding as of August 5, 2005.

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In this report, unless the context requires otherwise, references to "we", "us", "our", or the "Partnership" are intended to mean Enbridge Energy Partners, L.P. and its consolidated subsidiaries. This Quarterly Report on Form 10-Q contains forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as "anticipate," "believe," "continue," "estimate," "expect," "forecast," "intend," "may," "plan," "position," "projection," "strategy," "could," "would," or "will" or the negative of those terms or other variations of them or by comparable terminology. In particular, statements, expressed or implied, concerning future actions, conditions or events or future operating results or the ability to generate sales, income or cash flow or to make distributions are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or predict. For additional discussion of risks, uncertainties and assumptions, see our Annual Report on Form 10-K for the fiscal year ended December 31, 2004.

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

ENBRIDGE ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF INCOME

	Three months ended June 30, 2005	Three months ended June 30, 2004	Six months ended June 30, 2005	Six months ended June 30, 2004
	(unaudited; in millions, except per unit amounts)			
Operating revenue	$1,332.7	$969.7	$2,582.8	$1,952.2
Operating expenses				
Cost of natural gas (Note 4)	1,150.4	797.5	2,222.6	1,619.3
Operating and administrative	80.4	68.2	154.8	130.5
Power	17.2	17.1	34.2	34.3
Depreciation and amortization	34.1	28.9	67.4	57.5
	1,282.1	911.7	2,479.0	1,841.6
Operating income	50.6	58.0	103.8	110.6
Interest expense	(25.6)	(22.0)	(51.2)	(43.6)
Other income (expense)	0.7	(0.1)	1.3	2.0
Net income	$ 25.7	$ 35.9	$ 53.9	$ 69.0
Net income allocable to common and i-units	$ 19.9	$ 30.4	$ 42.1	$ 58.0
Net income per common and i-unit (basic and diluted) (Note 3)	$ 0.32	$ 0.56	$ 0.69	$ 1.06
Weighted average units outstanding	61.9	54.9	61.3	54.8

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended June 30,		Six months ended June 30,	
	2005	2004	2005	2004
	(unaudited; in millions)			
Net income	$ 25.7	$35.9	$ 53.9	$ 69.0
Unrealized loss on derivative financial instruments	(11.5)	(5.9)	(85.7)	(24.9)
Comprehensive (loss) income	$ 14.2	$30.0	$(31.8)	$ 44.1

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six months ended June 30, 2005	2004
	(unaudited; in millions)	
Cash provided by operating activities		
Net income	$ 53.9	$ 69.0
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	67.4	57.5
Derivative fair value loss (Note 4)	16.8	1.7
Environmental liabilities	—	(2.0)
Other	(0.3)	—
Changes in operating assets and liabilities, net of cash acquired:		
Receivables, trade and other	(5.8)	4.0
Due from General Partner and affiliates	(13.8)	6.9
Accrued receivables	(2.2)	(90.9)
Inventory	(10.2)	(16.7)
Current and long-term other assets	(2.8)	11.0
Due to General Partner and affiliates	20.7	2.8
Accounts payable and other	(17.3)	9.3
Accrued purchases	16.9	92.2
Interest payable	4.1	8.9
Property and other taxes payable	(3.7)	0.4
Net cash provided by operating activities	123.7	154.1
Cash used in investing activities		
Additions to property, plant and equipment	(174.7)	(70.8)
Changes in construction payables	2.2	1.0
Asset acquisitions, net of cash acquired (Note 2)	(185.9)	(130.0)
Other	0.8	0.1
Net cash used in investing activities	(357.6)	(199.7)
Cash provided by financing activities		
Proceeds from unit issuances, net (Note 7)	127.5	22.0
Distributions to partners (Note 7)	(104.0)	(93.6)
Borrowings under debt agreements	1,837.0	855.8
Repayments of debt	(1,622.0)	(732.5)
Other	(0.5)	—
Net cash provided by financing activities	238.0	51.7
Net increase in cash and cash equivalents	4.1	6.1
Cash and cash equivalents at beginning of year	78.3	64.4
Cash and cash equivalents at end of period	$ 82.4	$ 70.5

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	June 30, 2005	December 31, 2004
	(unaudited; in millions)	
ASSETS		
Current assets		
Cash and cash equivalents (Note 5)	$ 82.4	$ 78.3
Receivables, trade and other, net of allowance for doubtful accounts of $3.9 in 2005 and $4.0 in 2004	77.5	71.7
Due from General Partner and affiliates	21.5	7.7
Accrued receivables	380.4	378.2
Inventory	91.6	84.5
Other current assets	13.7	13.4
	667.1	633.8
Property, plant and equipment, net	3,061.3	2,778.0
Other assets, net	26.1	27.7
Goodwill	258.2	257.2
Intangibles, net	86.5	74.0
	$4,099.2	$3,770.7
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Due to General Partner and affiliates	$ 30.6	$ 9.9
Accounts payable and other (Note 5)	137.7	136.4
Accrued purchases	368.3	351.4
Interest payable	11.6	12.3
Property and other taxes payable	19.6	23.3
Current maturities of long-term debt	31.0	31.0
	598.8	564.3
Long-term debt	1,773.9	1,559.4
Loans from General Partner and affiliates	146.9	142.1
Environmental liabilities (Note 8)	5.0	5.3
Deferred credits	185.0	101.7
	2,709.6	2,372.8
Commitments and contingencies (Note 8)		
Partners' capital		
Class A common units (Units issued—46,802,634 in 2005 and 44,296,134 in 2004)	1,083.2	1,021.6
Class B common units (Units issued—3,912,750 in 2005 and 2004)	67.6	66.7
i-units (Units issued—11,306,254 in 2005 and 10,902,409 in 2004)	412.6	399.4
General Partner	32.7	31.0
Accumulated other comprehensive loss	(206.5)	(120.8)
	1,389.6	1,397.9
	$4,099.2	$3,770.7

The accompanying notes are an integral part of these consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

1. BASIS OF PRESENTATION

The accompanying unaudited interim consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America for interim consolidated financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. Accordingly, they do not include all the information and footnotes required by accounting principles generally accepted in the United States of America for complete consolidated financial statements. In the opinion of management, they contain all adjustments, consisting only of normal recurring adjustments, which management considers necessary to present fairly the financial position as of June 30, 2005 and December 31, 2004; and the results of operations for the three and six month periods ended June 30, 2005 and 2004; and cash flows for the six month periods ended June 30, 2005 and 2004. The results of operations for the three and six months ended June 30, 2005, should not be taken as indicative of the results to be expected for the full year due to seasonality of portions of the natural gas business, maintenance activities and the impact of forward natural gas prices on certain derivative financial instruments that are accounted for using mark-to-market accounting. In addition, prior period information presented in these consolidated financial statements includes reclassifications that were made to conform to the current period presentation. These reclassifications have no effect on previously reported net income or partners' capital. The interim consolidated financial statements should be read in conjunction with our consolidated financial statements and notes presented in our Annual Report on Form 10-K for the fiscal year ended December 31, 2004.

2. ACQUISITIONS

North Texas Natural Gas System

In January 2005, we acquired natural gas gathering and processing assets for $164.6 million in cash, including transaction costs of $0.5 million. We funded the acquisition with borrowings under our existing credit facilities. The assets acquired serve the Fort Worth Basin, which is mature, but experiencing minimal production decline rates and include:

- 2,200 miles of gas gathering pipelines; and
- four processing plants with aggregate processing capacity of 121 million cubic feet of natural gas per day ("MMcf/d").

The system provides cash flow primarily from purchasing raw natural gas from producers at the wellhead, processing the gas and then selling the natural gas liquids ("NGLs") and residue gas streams. The assets and results of operations are included in our Natural Gas segment from the date of acquisition.

The purchase price and the allocation to assets acquired and liabilities assumed was as follows (in millions):

Purchase Price:	
Cash paid, including transaction costs	$164.6
Allocation of purchase price:	
Property, plant and equipment, including construction in progress	151.6
Intangibles, including contracts	14.3
Current liabilities	(0.9)
Contingent liabilities	(0.4)
Total	$164.6

Other Acquisitions

In June 2005, we acquired for $20.1 million in cash, a natural gas pipeline and related facilities consisting of 92 miles of 20-inch diameter pipe that extends from Pampa, Texas into Western Oklahoma and has interconnects with our Anadarko system. We are integrating this pipeline into our existing Anadarko system and have included the assets and operating results in our Natural Gas segment from the date of acquisition. The purchase price for this acquisition was allocated to property, plant and equipment for $19.1 million and goodwill for $1.0 million. We also acquired other gathering and processing assets for approximately $1.2 million in cash.

3. NET INCOME PER COMMON AND i-UNIT

Net income per common and i-unit is computed by dividing net income, after deduction of Enbridge Energy Company, Inc.'s (the "General Partner") allocation, by the weighted average number of Class A and Class B common units and i-units outstanding. The General Partner's allocation is equal to an amount based upon its general partner interest, adjusted to reflect an amount equal to its incentive distributions and an amount required to reflect depreciation on the General Partner's historical cost basis for assets contributed on formation of the Partnership. There are no dilutive securities. Net income per common and i-unit was determined as follows:

	Three months ended June 30,		Six months ended June 30,	
	2005	2004	2005	2004
	(in millions, except per unit amounts)			
Net income	$25.7	$35.9	$ 53.9	$ 69.0
Allocations to the General Partner:				
Net income allocated to General Partner	(0.5)	(0.7)	(1.1)	(1.4)
Incentive distributions to General Partner	(5.3)	(4.8)	(10.6)	(9.5)
Historical cost depreciation adjustments	—	—	(0.1)	(0.1)
	(5.8)	(5.5)	(11.8)	(11.0)
Net income allocable to common and i-units	$19.9	$30.4	$ 42.1	$ 58.0
Weighted average units outstanding	61.9	54.9	61.3	54.8
Net income per common and i-unit (basic and diluted)	$0.32	$0.56	$ 0.69	$ 1.06

4. FINANCIAL INSTRUMENTS—COMMODITY PRICE RISK

Our net income and cash flows are subject to volatility stemming from changes in commodity prices of natural gas, NGLs, condensate and fractionation margins (the relative price differential between NGL sales and offsetting natural gas purchases). This market price exposure exists within our Natural Gas and Marketing segments. To mitigate the volatility of our cash flows, we use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the purchase and sales prices of the commodities. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or anticipated transaction and are not entered into with the objective of speculating on commodity prices.

Accounting Treatment

All derivative financial instruments are recorded in the consolidated financial statements at fair market value and are adjusted each period for changes in the fair market value ("mark-to-market"). Under the guidance of Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Transactions and Hedging Activities* ("SFAS No. 133"), changes in the fair market value of derivatives that qualify as highly effective cash flow hedges are recorded as components of Accumulated other comprehensive loss until the hedged transactions occur ("hedge accounting"). Hedge accounting can apply to either a hedge of future cash flows or the fair value of an asset or liability. Any ineffective portion of a cash flow hedge's change in fair value is recognized each period in earnings. When the hedged transaction occurs, the fair value of the derivative is recognized in earnings, along with the offsetting fair value of the physical transaction. For those derivative financial instruments that do not qualify for cash flow hedge accounting, the total change in fair value is recorded directly in earnings each period. Our preference, whenever possible, is for our derivative financial instruments to receive hedge accounting treatment in order to mitigate the noncash earnings volatility that arises under mark-to-market accounting treatment. However, to qualify for cash flow hedge accounting, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

Non-Qualified Hedges

Many of our derivative financial instruments qualify for hedge accounting treatment under the specific requirements of SFAS No. 133. However, we have three primary instances where the hedge structure does not meet the requirements to apply hedge accounting and therefore, these financial instruments are considered 'non-qualified' under SFAS No. 133. In these instances, the impacts of mark-to-market accounting for our non-qualified hedges are recorded in our Consolidated Statements of Income. These non-qualified derivative financial instruments must be adjusted to their fair market value, or marked-to-market, each period, with the increases and decreases in fair value recorded as increases and decreases in Cost of natural gas on our Consolidated Statements of Income. These mark-to-market adjustments produce a degree of earnings volatility that can often be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the underlying physical transaction takes place in the future and an associated financial instrument contract settlement is made.

The three instances of non-qualified hedges are as follows:

1. In our Marketing segment, when the pricing index used for gas sales is different from the pricing index used for gas purchases, we are exposed to relative changes in those two indices. By entering into a basis swap between those two indices, we can effectively lock in the margin on the combined gas purchase and gas sale, removing any market price risk on the physical transactions. Although this represents a sound economic hedging strategy, these types of derivative transactions do not qualify for hedge accounting under SFAS No. 133, as the ultimate cash flow has not been fixed, only the margin.

2. In our Marketing segment, when we use derivative financial instruments to hedge market spreads around our owned or contracted assets, such as our gas storage portfolio, the underlying forecasted transaction may or may not occur in the same period as originally forecast. This can occur as we have the flexibility to make these changes in the underlying injection or withdrawal schedule, given changes in market conditions. Therefore, these transactions do not qualify for hedge accounting treatment under SFAS No. 133, as the forecasted transaction is no longer probable of occurring as originally set forth in the hedge documentation.

3. In our Natural Gas segment, we had previously entered into natural gas collars in order to hedge the sales price of natural gas. The natural gas collars were based on a NYMEX price while the physical gas sales were based on a different index. To better align the index of the natural gas collars with the index of the underlying sales, we de-designated the original hedging relationship and contemporaneously re-designated the natural gas collars as hedges of physical natural gas sales with a NYMEX pricing index to better match the indices. This is a sound economic hedging strategy, however, since these instruments were out of the money at re-designation, they are

considered net written options under SFAS No. 133. Therefore, these instruments do not qualify for hedge accounting upon re-designation and are now accounted for in the Consolidated Statements of Income through mark-to-market accounting, with their changes in fair value from the date of de-designation recorded to earnings each period. As a result, our operating income will be subject to greater volatility due to movements in the prices of natural gas until these underlying long-term transactions are settled.

Discontinuance of Hedge Accounting

During the second quarter of 2005, we discontinued application of hedge accounting in connection with some of our derivative financial instruments designated as hedges of forecasted sales and purchases of natural gas. We discontinued application of hedge accounting when we determined it was no longer probable that the originally forecasted purchases and sales of natural gas would occur by the end of the originally specified time period, or within an additional two-month period of time thereafter. One of the key criteria to achieve hedge accounting under SFAS No. 133, is that the forecasted transaction is probable of occurring as originally documented in the hedge documentation. As a result, we recognized previously deferred unrealized losses in our Marketing segment of approximately $9.0 million from the discontinuance of hedge accounting. In doing so, we reclassified the $9.0 million to Cost of natural gas on our Consolidated Statements of income from Accumulated other comprehensive income. Going forward, the discontinued derivative financial instruments are considered to be non-qualified under SFAS No. 133, and must now be marked-to-market each period, with the increases and decreases in fair value recorded as increases and decreases in earnings. Included in the loss from discontinuance are approximately $2.1 million of net mark-to-market losses that relate to hedge positions that were closed-out during the second quarter.

The following table presents the gains and losses associated with changes in the fair value of our derivatives which are recorded as an element of Cost of natural gas in our Consolidated Statements of Income and disclosed as a reconciling item on our Statements of Cash Flows:

Derivative fair value gains (losses)	Three months ended June 30, 2005	Three months ended June 30, 2004	Six months ended June 30, 2005	Six months ended June 30, 2004
	(in millions)			
Natural Gas segment				
Ineffectiveness	$(1.8)	$ —	$ (2.0)	$ —
Non-qualified hedges	(2.9)	—	(11.1)	—
Marketing				
Non-qualified hedges	3.9	(1.9)	5.3	(1.7)
Discontinuance	(9.0)	—	(9.0)	—
Derivative fair value loss	$(9.8)	$(1.9)	$(16.8)	$(1.7)

We record the change in fair value of our highly effective cash flow hedges in our Consolidated Statements of Comprehensive Income until the derivative financial instruments are settled, at which time they are reclassified to earnings. For the three and six months ended June 30, 2005, we reclassified unrealized losses of $9.4 million and $25.2 million from Accumulated other comprehensive loss to Cost of natural gas on our Consolidated Statements of Income for the fair value of derivative financial instruments that were settled.

Our derivative financial instruments are included at their fair values in the Consolidated Statements of Financial Position as follows:

	June 30, 2005	December 31, 2004
	(in millions)	
Receivables, trade and other	$ 5.3	$ 8.2
Other assets, net	9.4	10.1
Accounts payable and other	(60.8)	(45.9)
Deferred credits	(182.5)	(99.6)
	$(228.6)	$(127.2)

The increase in our obligation associated with our derivative activities from December 31, 2004 to June 30, 2005 is primarily due to the significant increases in forward natural gas and NGL prices. The Partnership's portfolio of derivative financial instruments is largely comprised of long-term fixed price sales agreements.

We do not require collateral or other security from the counterparties to our derivative financial instruments. All of our counterparties were rated "A" or better by all major credit rating agencies.

5. CASH AND CASH EQUIVALENTS

We extinguish liabilities when a creditor has relieved us of our obligation, which occurs when our financial institution honors a check that the creditor has presented for payment. Accordingly, obligations for which we have issued check payments that have not yet been presented to the financial institution of approximately $25.6 million at June 30, 2005 and $25.3 million at December 31, 2004, are included in Accounts payable and other on the Consolidated Statements of Financial Position.

6. DEBT

Amendment to Credit Agreement

In April 2005, we entered into the third amendment to the Amended and Restated Credit Agreement dated as of January 24, 2003 (the "Credit Facility") to, among other things, extend the maturity of the Credit Facility for a period of five years to April 2010; increase the letter of credit sublimit from $100 million to $175 million; and grant us the right to request, subject to approval by the Board of Directors of Enbridge Energy Management, L.L.C. ("Enbridge Management"), an increase in commitments available under the Credit Facility up to an aggregate outstanding principal amount of $1 billion. At June 30, 2005, our Credit Facility has no outstanding borrowings.

Commercial Paper Program

In April 2005, we successfully entered the commercial paper market with the establishment of our $600 million commercial paper program that is backstopped by our Credit Facility. We access the commercial paper market primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions, at rates that are generally lower than the rates available under our Credit Facility. We repaid the entire amount previously outstanding under our Credit Facility with proceeds we obtained from issuing commercial paper under this program. Under the terms of our commercial paper program, we can issue commercial paper up to the $600 million limit of our Credit Facility, reduced by the balance of outstanding Letters of Credit. At June 30, 2005, we had outstanding $390.0 million of commercial paper at a weighted average interest rate of 3.23% and outstanding Letters of Credit totaling $121.2 million. Availability under our commercial paper program is $88.8 million at June 30, 2005.

7. PARTNERS' CAPITAL

The following table sets forth the distributions, as approved by the Board of Directors of Enbridge Management through June 30, 2005:

Distribution Declaration Date	Distribution Payment Date	Ex-Distribution Date	Distribution per Unit	Cash available for distribution	Amount of Distribution of i-units to i-unit Holders[(1)]	Retained from General Partner[(2)]	Distribution of Cash
				(in millions, except per unit amounts)			
April 25, 2005	May 13, 2005	May 4, 2005	$0.925	$ 63.8	$10.3	$0.2	$ 53.3
January 24, 2005	February 14, 2005	February 3, 2005	0.925	61.0	10.1	0.2	50.7
				$124.8	$20.4	$0.4	$104.0

(1) The Partnership has issued 403,845 i-units to Enbridge Management, the sole owner of the Partnership's i-units during 2005 in lieu of cash distributions.

(2) The Partnership retains an amount equal to 2% of the i-unit distribution from the General Partner in respect of its 2% general partner interest.

Common unit offering

On February 11, 2005, we issued 2,506,500 Class A common units at $49.875 per unit, which generated proceeds of approximately $124.8 million, net of offering expenses. Additionally, the General Partner contributed $2.7 million to us to maintain its 2% general partner interest in the Partnership. We used the proceeds from this offering to repay amounts outstanding under our Credit Facility.

8. COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

Environmental Liabilities

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to liquid and gas pipeline operations and we could, at times, be subject to environmental cleanup and enforcement actions. We manage this environmental risk through appropriate environmental policies and practices to minimize any impact on the environment of our pipeline operations.

As of June 30, 2005 and December 31, 2004, we have recorded $3.8 million and $3.6 million in current liabilities and $5.0 million and $5.3 million in long-term liabilities, respectively, primarily to address remediation of contaminated sites, asbestos containing materials, management of hazardous waste material disposal, and outstanding air quality measures for certain liquids and natural gas assets.

Legal Proceedings

We are a participant in various legal proceedings arising in the ordinary course of business. Some of these proceedings are covered, in whole or in part, by insurance. We believe that the outcome of all these proceedings will not, individually or in the aggregate, have a material adverse effect on our financial condition.

9. SEGMENT INFORMATION

Our business is divided into operating segments, defined as components of the enterprise, about which, financial information is available and evaluated regularly by our Chief Operating Decision Maker in deciding how resources are allocated and performance is assessed.

Each of our reportable segments is a business unit that offers different services and products that are managed separately since each business segment requires different operating strategies. We have segregated our business activities into three distinct operating segments:

- Liquids;
- Natural Gas; and
- Marketing.

The following tables present certain financial information relating to our business segments:

	As of and for the three months ended June 30, 2005				
	Liquids	Natural Gas	Marketing	Corporate	Total
			(in millions)		
Total revenue	$102.5	$988.0	$802.1	$ —	$1,892.6
Less: Intersegment revenue	—	526.7	33.2	—	559.9
Operating revenue	102.5	461.3	768.9	—	1,332.7
Cost of natural gas	—	379.5	770.9	—	1,150.4
Operating and administrative	37.5	40.9	0.9	1.1	80.4
Power	17.2	—	—	—	17.2
Depreciation and amortization	17.7	16.2	0.2	—	34.1
Operating income	30.1	24.7	(3.1)	(1.1)	50.6
Interest expense	—	—	—	(25.6)	(25.6)
Other income	—	—	—	0.7	0.7
Net income	$ 30.1	$ 24.7	$ (3.1)	$(26.0)	$ 25.7
Capital expenditures (excluding acquisitions)	$ 21.6	$ 78.6	$ —	$ 1.6	$ 101.8

	As of and for the three months ended June 30, 2004				
	Liquids	Natural Gas	Marketing	Corporate	Total
			(in millions)		
Total revenue	$102.7	$630.4	$664.5	$ —	$1,397.6
Less: Intersegment revenue	—	395.5	32.4	—	427.9
Operating revenue	102.7	234.9	632.1	—	969.7
Cost of natural gas	—	166.9	630.6	—	797.5
Operating and administrative	33.4	33.3	0.8	0.7	68.2
Power	17.1	—	—	—	17.1
Depreciation and amortization	16.8	12.1	—	—	28.9
Operating income	35.4	22.6	0.7	(0.7)	58.0
Interest expense	—	—	—	(22.0)	(22.0)
Other expense	—	—	—	(0.1)	(0.1)
Net income	$ 35.4	$ 22.6	$ 0.7	$(22.8)	$ 35.9
Capital expenditures (excluding acquisitions)	$ 18.9	$ 29.4	$ —	$ 0.9	$ 49.2

	As of and for the six months ended June 30, 2005				
	Liquids	Natural Gas	Marketing (in millions)	Corporate	Total
Total revenue	$ 199.0	$1,912.6	$1,495.9	$ —	$3,607.5
Less: Intersegment revenue	—	965.7	59.0	—	1,024.7
Operating revenue	199.0	946.9	1,436.9	—	2,582.8
Cost of natural gas	—	786.0	1,436.6	—	2,222.6
Operating and administrative	69.4	82.0	1.7	1.7	154.8
Power	34.2	—	—	—	34.2
Depreciation and amortization	35.3	31.8	0.3	—	67.4
Operating income	60.1	47.1	(1.7)	(1.7)	103.8
Interest expense	—	—	—	(51.2)	(51.2)
Other income	—	—	—	1.3	1.3
Net income	$ 60.1	$ 47.1	$ (1.7)	$(51.6)	$ 53.9
Total assets	$1,670.8	$2,053.3	$ 280.6	$ 94.5	$4,099.2
Goodwill	$ —	$ 237.8	$ 20.4	$ —	$ 258.2
Capital expenditures (excluding acquisitions)	$ 34.7	$ 137.3	$ —	$ 2.7	$ 174.7

	As of and for the six months ended June 30, 2004				
	Liquids	Natural Gas	Marketing (in millions)	Corporate	Total
Total revenue	$ 194.4	$1,294.9	$1,261.4	$ —	$2,750.7
Less: Intersegment revenue	—	725.3	73.2	—	798.5
Operating revenue	194.4	569.6	1,188.2	—	1,952.2
Cost of natural gas	—	435.6	1,183.7	—	1,619.3
Operating and administrative	61.2	65.7	1.6	2.0	130.5
Power	34.3	—	—	—	34.3
Depreciation and amortization	32.9	24.6	—	—	57.5
Operating income	66.0	43.7	2.9	(2.0)	110.6
Interest expense	—	—	—	(43.6)	(43.6)
Other income	—	—	—	2.0	2.0
Net income	$ 66.0	$ 43.7	$ 2.9	$(43.6)	$ 69.0
Total assets	$1,638.9	$1,522.9	$ 277.8	$ 28.5	$3,468.1
Goodwill	$ —	$ 237.0	$ 20.3	$ —	$ 257.3
Capital expenditures (excluding acquisitions)	$ 26.8	$ 42.7	$ —	$ 1.3	$ 70.8

10. SUBSEQUENT EVENTS

Distribution to Partners

On July 28, 2005, Enbridge Management's Board of Directors declared a distribution payable to our partners on August 12, 2005. The distribution will be paid to unitholders of record as of August 5, 2005, of our available cash of $64.0 million at June 30, 2005, or $0.925 per common unit. Of this distribution,

$53.3 million will be paid in cash, $10.5 million will be distributed in i-units to our i-unitholder and $0.2 million will be retained from the General Partner in respect of this i-unit distribution.

11. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Accounting for Conditional Asset Retirement Obligations

In March 2005, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143*. This interpretation clarifies the meaning of "conditional asset retirement obligation" as used in FASB Statement No. 143, *Accounting for Asset Retirement Obligations* as referring to a legal obligation to perform an asset retirement activity where the timing and/or method of settlement are conditional on a future event that may or may not be within the control of an entity. The obligation to perform the retirement activity is unconditional even though uncertainty may exist about the timing and/or method of settlement. The interpretation requires an entity to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. This interpretation is effective no later than the end of fiscal years ending after December 15, 2005. We are currently evaluating the effect that application of this interpretation will have on our financial statements.

Accounting Changes and Error Corrections

In May 2005, the FASB issued Statement of Financial Accounting Standards No. 154, *Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statement No. 3*. Under this statement, voluntary changes in accounting principle are required to be applied retrospectively for the direct effects of a change to prior periods' financial statements, unless such application is impracticable. Retrospective application refers to reflecting a change in accounting principle in the financial statements of prior periods as if the principle had always been used. When retrospective application is determined to be impracticable, this statement requires the new accounting principle to be applied to the balances of assets and liabilities as of the beginning of the earliest period for which retrospective treatment is practicable with a corresponding adjustment to the opening balance of retained earnings. This statement retains the guidance in APB Opinion No. 20 for reporting the corrections of errors and changes in accounting estimates. This statement is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005, with early adoption permitted. Our adoption of this statement will effect our consolidated financial statements for any changes in accounting principle we may make in the future, or new pronouncements we adopt that do not provide transition provisions.

FERC Guidance on Accounting for Integrity Management Costs

In June 2005, the Federal Energy Regulatory Commission ("FERC") issued guidance describing how FERC-regulated companies should account for costs associated with implementing the pipeline integrity management requirements of the U.S. Department of Transportation's Office of Pipeline Safety. Under the guidance, costs to 1) prepare a plan to implement the program, 2) identify high consequence areas, 3) develop and maintain a record keeping system and 4) inspect, test and report on the condition of affected pipeline segments to determine the need for repairs or replacements, are required to be expensed. Costs of modifying pipelines to permit in-line inspections, certain costs associated with developing or enhancing computer software and costs associated with remedial and mitigation actions to correct an identified condition can be capitalized. The guidance is effective January 1, 2006, to be applied prospectively. We are currently evaluating the effect that application of this order will have on our financial statements.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

RESULTS OF OPERATIONS—OVERVIEW

We provide services to our customers and create value for our unitholders primarily through the following activities:

- Interstate transportation and storage of crude oil and liquid petroleum;
- Gathering, treating, processing and transmission of natural gas; and
- Providing supply, transmission and sales service, including purchasing and selling natural gas and natural gas liquids ("NGLs").

We primarily provide fee-based services to our customers to minimize commodity price risks. However, in our natural gas and marketing businesses, a portion of our earnings and cash flows are exposed to movements in the prices of natural gas and NGLs. To substantially mitigate this exposure, we enter into derivative financial instrument transactions. Certain of these transactions qualify for hedge accounting under Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Transactions and Hedging Activities* ("SFAS No. 133"), some however, must be accounted for using the mark-to-market method of accounting.

We conduct our business through three business segments: Liquids, Natural Gas and Marketing. These segments are strategic business units established by senior management to facilitate the achievement of our long-term objectives, to aid in resource allocation decisions and to assess operational performance.

The following table reflects operating income by business segment and corporate charges for each of the periods presented.

	Three months ended June 30,		Six months ended June 30,	
	2005	2004	2005	2004
	(unaudited; in millions)			
Operating Income				
Liquids	$ 30.1	$ 35.4	$ 60.1	$ 66.0
Natural Gas	24.7	22.6	47.1	43.7
Marketing	(3.1)	0.7	(1.7)	2.9
Corporate, operating and administrative	(1.1)	(0.7)	(1.7)	(2.0)
Total Operating Income	50.6	58.0	103.8	110.6
Interest expense	(25.6)	(22.0)	(51.2)	(43.6)
Other income	0.7	(0.1)	1.3	2.0
Net Income	$ 25.7	$ 35.9	$ 53.9	$ 69.0

Consolidated net income for the three and six months ended June 30, 2005, was $25.7 million and $53.9 million compared with $35.9 million and $69.0 million for the same periods of 2004. The decrease in net income is attributable to lower transportation volumes on our Liquids segment, non-cash mark-to-market losses of $9.8 million and $16.8 million from derivative transactions in our Natural Gas and Marketing segments for the respective periods, as well as higher interest expense. The decreases in our net income were partially offset by increased volumes in our Natural Gas segment coupled with increases in natural gas and NGL prices.

Earnings per unit decreased to $0.32 per unit and $0.69 per unit for the three and six months ended June 30, 2005, representing declines from the $0.56 per unit and $1.06 per unit we reported for the comparable periods in 2004. Earnings per unit were lower for the second quarter of 2005 due to the decrease in net income and an increase in the number of common units outstanding. Since the second quarter of 2004, we have issued 6,186,500 Class A common units and 848,833 i-units that have increased the weighted average number of our common units outstanding to 61.9 million and 61.3 million for the three and six months ended June 30, 2005, from 54.9 million and 54.8 million for the same periods in 2004.

We acquired natural gas gathering and processing assets in North Texas in January 2005. The facilities acquired include approximately 2,200 miles of natural gas gathering pipelines and four natural gas processing plants with an aggregate processing capacity of 121 million cubic feet per day ("MMcf/d") of natural gas. This system predominantly serves producers in the Fort Worth Basin Conglomerate formation and is located in an area where we expect future drilling by producers extending the Barnett Shale play's western flank. We combined these assets with our existing North Texas assets and have included them in the operating results of our Natural Gas segment from the date of acquisition. In late June 2005, we also acquired an idle 92 mile natural gas pipeline that extends from the Texas Panhandle to Western Oklahoma which we are integrating with our existing Anadarko system. Although this pipeline did not contribute to our operating results for the quarter and six months ended June 30, 2005, we expect this pipeline to improve service to existing customers and allow us to attract additional production in future periods.

RESULTS OF OPERATIONS—BY SEGMENT

Liquids

The following tables sets forth the operating results and statistics of our Liquids segment assets for the periods presented:

	Three months ended June 30,		Six months ended June 30,	
	2005	2004	2005	2004
	(unaudited; in millions)			
Operating Results				
Operating revenues	$102.5	$102.7	$ 199.0	$ 194.4
Operating and administrative	(37.5)	(33.4)	(69.4)	(61.2)
Power	(17.2)	(17.1)	(34.2)	(34.3)
Depreciation and amortization	(17.7)	(16.8)	(35.3)	(32.9)
Expenses	(72.4)	(67.3)	(138.9)	(128.4)
Operating Income	$ 30.1	$ 35.4	$ 60.1	$ 66.0
Operating Statistics				
Lakehead system:				
United States[(1)]	1,052	1,103	1,031	1,059
Province of Ontario[(1)]	277	355	302	373
Total deliveries[(1)]	1,329	1,458	1,333	1,432
Barrel miles (billions)	84	92	167	182
Average haul (miles)	692	697	691	700
Mid-Continent system deliveries[(1)]	226	205	208	214
North Dakota system deliveries[(1)]	89	85	89	79

(1) Average barrels per day ("Bpd") in thousands.

Three months ended June 30, 2005 compared with three months ended June 30, 2004

Our Liquids segment accounted for $30.1 million of operating income, or 59% of consolidated operating income in the second quarter of 2005. This was a decrease of $5.3 million in operating income over the same period in 2004. Lower results on the Lakehead and Mid-Continent systems were slightly offset by stronger results on the North Dakota system.

Operating revenue for the second quarter of 2005 was consistent with the same period in 2004. Overall tariff increases, higher deliveries on our Mid-Continent and North Dakota systems, and longer hauls on our North Dakota system, were more than offset by lower results on the Lakehead system.

Increases in average tariffs on all three Liquids systems resulted in higher operating revenue by approximately $6.2 million. These tariff increases were mostly the result of the annual index rate increase of approximately 3.17% allowed by the Federal Energy Regulatory Commission ("FERC") effective July 1, 2004 and the Terrace and Facilities Surcharges on the Lakehead system, that were not in effect during the second quarter of 2004. Longer hauls on our North Dakota system also contributed to a higher average tariff, as production in Montana has been strong.

Volumes on the Lakehead system decreased approximately 9%, from 1.458 million Bpd during the second quarter of 2004 to 1.329 million Bpd during the same period in 2005. This resulted in lower operating revenue of approximately $7.9 million. The decrease is primarily the result of lower than expected supply in Western Canada from Suncor, an oil sands producer in Alberta, Canada. On January 4, 2005, a fire occurred at their upgrader site and since that time, production has been reduced by an average of 90,000 Bpd compared to the same period in 2004. Suncor has stated that plans are to return to full production capacity in September 2005. Until that time, we expect deliveries on the Lakehead system to be negatively impacted by the decreased Suncor production. Western Canadian crude oil supply available for delivery on our Lakehead system was also reduced during the second quarter of 2005, compared to the same period in 2004, due to timing differences. Bitumen production was lower during the second quarter of 2005, as the nature of the cyclic steaming process used to extract it from the ground can cause production timing differences during the year. Also, refinery turnarounds in Alberta that took place in 2004 did not recur in the second quarter of 2005, thereby lowering the amount of crude oil available for delivery on the Lakehead system in 2005. Finally, during the second quarter of 2005, Terasen Inc., operator of the Express Pipeline which transports western Canadian crude to the U.S. Rocky Mountain market, completed an expansion on their Express Pipeline. This expansion increased capacity on their pipeline by approximately 108,000 Bpd. Given the volume commitments on the Express Pipeline expansion, coupled with the lower western Canadian crude oil supply as noted above, deliveries on our Lakehead system were negatively impacted during the second quarter of 2005. Holders of firm capacity on the Express Pipeline will first satisfy their commitments to that pipeline before moving incremental barrels on the Lakehead system.

Operating and administrative expenses for the Liquids segment increased $4.1 million or 12% in the second quarter of 2005, compared with the same period in 2004. Capital project recoveries are lower by approximately $1.4 million due to a decrease in utilization of our workforce on capital projects and a reduction in construction activity on our Lakehead system. Pipeline integrity work has increased on the Lakehead system during the second quarter of 2005, which resulted in higher operating costs of approximately $1.1 million. Oil measurement losses on the Lakehead system were higher in the second quarter of 2005 by approximately $0.8 million, primarily due to higher oil prices and wider light/heavy crude price differentials (see further explanation below in the six month analysis).

Six months ended June 30, 2005 compared to six months ended June 30, 2004

Our Liquids segment accounted for $60.1 million, or 58%, of consolidated operating income in the first half of 2005. This was a decrease of $5.9 million in operating income over the same period in 2004. Operating income decreased in 2005 for the same reason as noted above in the three-month analysis.

Operating revenue for the first six months of 2005 increased by $4.6 million to $199.0 million, compared with $194.4 million for the same period in 2004. The increase in average tariffs on all Liquids systems resulted in higher operating revenue of approximately $10.4 million for the reasons noted above in the three-month analysis. In 2005, our Mid-Continent assets contributed for a full six-month period compared to four months in 2004, which resulted in higher operating revenue of approximately $7.8 million. These increases were mostly offset by lower deliveries on the Lakehead system for the same reason as noted above in the three-month analysis. This resulted in a decrease of approximately $13.1 million in operating revenue in the second quarter of 2005.

Operating and administrative expenses for the first six months of 2005 increased by $8.2 million to $69.4 million, compared with $61.2 million for the same period in 2004. The increase is driven primarily from higher oil measurement losses of approximately $5.4 on the Lakehead system for the six-month period.

Oil measurement losses occur as part of the normal operating conditions associated with our Liquids pipelines. The three types of oil measurement losses include:

- physical losses, which occur through evaporation, shrinkage, differences in measurement between receipt and delivery locations and other operational incidents;
- degradation losses, which result from mixing at the interface between higher quality light crude oil and lower quality heavy crude oil in pipelines; and
- revaluation losses, which are a function of crude oil prices, the level of the carrier's inventory and the inventory positions of customers.

During the six months ended June 30, 2005, the increase in oil measurement losses was a function of three factors:

1. Higher volumetric physical losses associated with changes in commodity properties and measurement, coupled with higher oil prices that made the absolute value of even normal physical losses more expensive. During the first six months of 2005, the average West Texas Intermediate crude oil price was approximately $51 per barrel compared with approximately $36 per barrel during the same period in 2004;
2. Wider light/heavy crude price differentials made degradation losses more expensive. During the first six months of 2005, light/heavy differentials were approximately $20 per barrel compared with approximately $11 per barrel in 2004; and
3. Limited market liquidity is available to settle specific crude oil positions that are naturally created by our pipeline system's operations. Market liquidity is especially constrained when a price trend is anticipated by crude oil marketers. As a result, we carried net short positions that we could not physically settle during the first six months of 2005, on which we experienced a loss prior to settling the position.

Natural Gas

The following tables sets forth the operating results of our Natural Gas segment assets and average daily volumes of our major systems in millions of British Thermal units per day ("MMBtu/d") for the periods presented:

	Three months ended June 30,		Six months ended June 30,	
	2005	2004	2005	2004
	(unaudited; in millions)			
Operating Results				
Operating revenues	$ 461.3	$ 234.9	$ 946.9	$ 569.6
Cost of natural gas	(379.5)	(166.9)	(786.0)	(435.6)
Operating and administrative	(40.9)	(33.3)	(82.0)	(65.7)
Depreciation and amortization	(16.2)	(12.1)	(31.8)	(24.6)
Expenses	(436.6)	(212.3)	(899.8)	(525.9)
Operating Income	$ 24.7	$ 22.6	$ 47.1	$ 43.7
Operating Statistics (MMBtu/d)				
East Texas	833,000	655,000	810,000	619,000
Anadarko[1]	478,000	332,000	465,000	308,000
North Texas	260,000	188,000	262,000	190,000
South Texas	34,000	42,000	36,000	43,000
UTOS	191,000	218,000	194,000	212,000
MidLa	107,000	97,000	106,000	107,000
AlaTenn	53,000	54,000	68,000	67,000
KPC	19,000	27,000	39,000	58,000
Bamagas	9,000	35,000	11,000	22,000
Other Major Intrastates[1]	209,000	167,000	215,000	176,000
Total	2,193,000	1,815,000	2,206,000	1,802,000

(1) Anadarko includes the combined systems previously referred to separately as Anadarko and Palo Duro. The Palo Duro volumes were formerly included with Other Major Intrastates.

Three months ended June 30, 2005 compared with three months ended June 30, 2004

Our Natural Gas segment accounted for $24.7 million of operating income, or 49%, of consolidated operating income in the second quarter of 2005. This was an increase of $2.1 million in operating income over the corresponding period in 2004.

Average daily volumes on our major natural gas systems increased 21% in the second quarter of 2005, compared with the corresponding period in 2004. The increase in volumes is primarily the result of additional wellhead supply contracts on our East Texas and Anadarko systems as well as the additional volumes on the North Texas system associated with the acquisition of additional gathering and processing assets in January 2005. We expect volumes in these areas to continue to increase as a result of increased drilling activity in the Anadarko basin, the Bossier trend and the Barnett Shale area. Additionally, we anticipate transportation volumes to further increase on our East Texas system as a result of completing the 500 MMcf/d system expansion in late June 2005.

A portion of our Natural Gas segment is exposed to commodity price risks associated with percent of proceeds or percentage of index contracts that we negotiate with producers. Under the terms of these contracts, we retain a portion of the natural gas and NGLs we process in exchange for providing these producers with our services. In order to protect our unitholders from the volatility in cash flows that can result from fluctuations in commodity prices, we enter into derivative financial instruments to fix the sales price of the natural gas and NGLs we anticipate receiving under the terms of these contracts. As a result of entering into these derivative financial instruments, we have largely fixed the amount of cash that we will receive at the time we sell the processed natural gas and NGLs, although the market price of these commodities will continue to fluctuate. The remainder of the revenue we receive is derived from fees charged for gathering and treating of natural gas volumes and other related services.

A relatively small, but variable element of the Natural Gas segment's operating income is derived from keep-whole processing of natural gas. This contract structure requires us to process natural gas at times when it may not be economical to do so. This can happen when natural gas prices are unusually high or NGL prices are unusually low. During the second quarter of 2005, although natural gas prices were unusually high, they were more than offset by favorable NGL prices. Operating revenue less cost of natural gas derived from keep-whole processing for the three months ended June 30, 2005, was approximately $6.4 million compared with $0.9 million for the same period in 2004.

The positive growth in our natural gas and NGL gathering, processing and transportation volumes for the second quarter of 2005 was partially offset by increases in operating costs that are mostly variable with volumes. The higher volumes on the systems resulted in increases of workforce related costs approximating $1.4 million, and repair and maintenance costs of approximately $1.1 million. Operating costs were also higher in 2005 by $1.5 million of incremental costs associated with the natural gas gathering and processing assets we acquired in January 2005.

We included mark-to-market losses of $4.7 million in the Cost of natural gas, of which $1.8 million is due to ineffectiveness on our qualified cash flow hedges and $2.9 million is attributable to certain derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133 (refer also to the discussions included below under Derivative Transactions, Note 4 of Item 1. Financial Statements, and Item 3. Quantitative and Qualitative Disclosures About Market Risk). Although changes in the fair value of these specific derivative financial instruments do not affect our cash flow, we anticipate these changes will continue to create volatility in our Consolidated Statements of Income going forward due to the inherent volatility of natural gas and NGL prices.

Six months ended June 30, 2005 compared with six months ended June 30, 2004

Our Natural Gas segment accounted for $47.1 million of consolidated operating income for the six months ended June 30, 2005, an increase of 8% over the $43.7 million for the same period of 2004.

Average daily volumes on our major natural gas systems increased 22%, or 404,000 MMBtu/d, for the first half of 2005, compared with the corresponding period in 2004. The increase in volumes is primarily attributable to additional wellhead supply contracts on our East Texas and Anadarko systems, as well as the additional volumes on the North Texas system associated with the acquisition of additional gathering and processing assets in January 2005.

As previously noted under our three month analysis, a portion of our Natural Gas segment's operating income is derived from processing of natural gas under keep-whole arrangements. Operating revenue less cost of natural gas derived from keep-whole processing for the six months ended June 30, 2005, was approximately $10.5 million compared with $3.0 million for the same period in 2004.

Operating and administrative costs associated with our Natural Gas segment were $16.3 million greater for the six months ended June 30, 2005 over the same period of 2004. Approximately $3.2 million of the increase is attributable to the natural gas gathering and processing assets we acquired in January 2005. The down time for maintenance activities at three of our processing plants along with the $1.6 million we spent performing this maintenance also contributed to the increase. The remaining increase is primarily due to workforce related costs of $5.4 million attributable to additional personnel and associated benefit costs related to the volume growth on our systems.

Operating income from our Natural Gas segment during the six months ended June 30, 2005 was negatively affected by noncash losses from derivative transactions of $13.1 million, recorded in the Cost of natural gas. The losses consist of $11.1 million of mark-to-market adjustments on derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133 and $2.0 million of losses recognized for the ineffective portion of derivative financial instruments designated as cash flow hedges of natural gas purchase and sales transactions (refer also to the discussions included below under Derivative Transactions, Note 4 of Item 1. Financial Statements, and Item 3. Quantitative and Qualitative Disclosures About Market Risk). Although changes in the fair value of these specific derivative financial instruments do not affect our cash flow, we anticipate changes in the fair value of these contracts will continue to create volatility in our Consolidated Statements of Income going forward due to the inherent volatility of the natural gas and NGL prices.

Marketing

The following table sets forth the operating results for the Marketing segment assets for the periods presented:

	Three months ended June 30,		Six months ended June 30,	
	2005	2004	2005	2004
	(unaudited; in millions)			
Operating revenues	$ 768.9	$ 632.1	$ 1,436.9	$ 1,188.2
Cost of natural gas	(770.9)	(630.6)	(1,436.6)	(1,183.7)
Operating and administrative	(0.9)	(0.8)	(1.7)	(1.6)
Depreciation and amortization	(0.2)	—	(0.3)	—
Expenses	(772.0)	(631.4)	(1,438.6)	(1,185.3)
Operating Income (loss)	$ (3.1)	$ 0.7	$ (1.7)	$ 2.9

Three months ended June 30, 2005 compared with three months ended June 30, 2004

A majority of the operating income of our Marketing segment is derived from selling natural gas received from customers on our Natural Gas segment pipeline assets to end users of natural gas. A majority of the natural gas is purchased in Texas markets where we have limited physical access to the primary pricing points, or Hubs, such as WAHA and the Houston Ship Channel. As a result, our Marketing business must rely on third-party pipelines to transport the natural gas to the markets where it can be sold to end users. Wherever possible, our Marketing business will sell gas into these liquid market points. However, physical pipeline constraints often require our Marketing business to take natural gas to alternate market points. This creates price exposure for the relative difference in natural gas prices between the contracted index at which the natural gas is purchased and the index under which it is sold. The difference between the prices at which the natural gas is purchased and the prices at which it is sold can be significant due to supply and demand factors at locations where the natural gas is purchased and sold. Wherever possible, this pricing exposure is hedged using derivative financial instruments.

Our Marketing segment continues to be impacted by lower unit margins on natural gas volumes purchased due to physical pipeline constraints. The recent completion of our East Texas system expansion has partially alleviated these constraints; however, increasing production volumes will continue to create additional constraints, which will require continued use of third-party pipelines in East Texas. This situation is not limited to the East Texas region. Pricing in our natural gas supply markets is expected to continue to experience increasing pressure due to more natural gas supplies from the Rocky Mountains and North Texas. For this reason we have increased our commitments on third-party pipelines to provide more attractive market outlets for our natural gas supply. However, there continues to be timing differences between the acquisition of new capacity and the negotiation of applicable downstream sales agreements to match. Until new markets are developed, our Marketing segment sells greater portions of its natural gas supply in less attractive short-term markets.

In the second quarter of 2005, our Marketing segment incurred losses of $3.1 million compared with earning $0.7 million of operating income for the corresponding period in 2004. Included in operating loss for the second quarter of 2005 are mark-to-market gains of approximately $3.9 million associated with derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. These gains are offset by losses of approximately $9.0 million resulting from the discontinuance of hedge accounting for derivative financial instruments associated with forecasted transactions that we determined were not probable of occurring. In the second quarter of 2005, we revised our business strategy for the use of derivative financial instruments associated with transportation of natural gas to afford us the ability to enter and exit markets in response to changing economic conditions. The flexibility provided by the revised strategy precludes us from continuing the use of hedge accounting with regard to these transactions. As a result of adopting this strategy, we determined that our previously forecasted sales and purchases were not probable of occurring because of the likelihood the original transactions would be closed. We expect a majority of these net mark-to-market losses to be offset when the related physical transactions are settled. Approximately $2.1 million of the net mark-to-market losses will not be recoverable and relate to hedges closed-out during the second quarter. These amounts will be realized as reduced cash flows over an approximate 18 month period. The Partnership will use its best efforts to mitigate or recover economic losses on this portion of the discontinued derivative financial instruments (refer also to the discussion included below under Derivative Transactions, Note 4 of Item 1. Financial Statements, and Item 3. Quantitative and Qualitative Disclosures About Market Risk).

The Partnership uses derivative financial instruments to economically hedge potential commodity price movements. Specifically, natural gas swaps and certain storage swaps are strategies commonly used. Financial natural gas basis swap transactions are employed to mitigate the risk on index pricing differentials between physical natural gas purchases and corresponding natural gas sales. When the natural gas sales pricing index is different from the natural gas purchase pricing index, the Partnership is exposed to relative changes in those two index levels. By entering into a basis swap between those two indices, the Partnership can effectively lock in the margin on the combined natural gas purchase and the natural gas sale, removing any market price risk on the physical transactions. In addition to natural gas basis swaps, the Partnership contracts for storage to assist balancing natural gas supply and end use market sales. In order to mitigate storage fees for the use of the storage capacity, the forward price between the summer and winter ("spread") is hedged by buying forward storage injection swaps and selling storage withdrawal swaps. When these spread values increase or decrease as a result of market price movements, the Partnership earns additional profitability through the optimization of those hedges in both the forward and daily markets. Although each of these hedge strategies are sound economic hedging techniques, these types of financial transactions do not qualify for hedge accounting under the SFAS No. 133 guidelines. As such, the non-qualified hedges are accounted for on a mark-to-market basis, and the periodic change in their market value, although non-cash, will impact the income statement.

Six months ended June 30, 2005 compared with six months ended June 30, 2004

Our Marketing segment incurred an operating loss of $1.7 million in the first half of 2005, compared with $2.9 million of operating income for the corresponding period in 2004. Included in the operating loss for the six months of 2005 are mark-to-market gains of approximately $5.3 million associated with derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. These gains are offset by losses of approximately $9.0 million resulting from the discontinuance of hedge accounting for derivative financial instruments associated with forecasted transactions that we determined were not probable of occurring as discussed above in our three month analysis (refer also to the discussion included below under Derivative Transactions, Note 4 of Item 1. Financial Statements, and Item 3. Quantitative and Qualitative Disclosures About Market Risk).

Corporate

Interest expense was $25.6 million and $51.2 million for the three and six months ended June 30, 2005, respectively, compared with $22.0 million and $43.6 million for the corresponding periods in 2004. The increases are the result of higher debt balances and higher weighted average interest rates of approximately 5.72% and 5.86% during the three and six months ended June 30, 2005, compared with approximately 5.39% and 5.24% during the same periods in 2004.

LIQUIDITY AND CAPITAL RESOURCES

We believe that our ability to generate cash flow, in addition to our access to capital resources, is sufficient to meet the demands of our current and future operating growth and investment needs. Our primary cash requirements consist of normal operating expenses, maintenance and expansion capital expenditures, debt service payments, distributions to partners and acquisitions of new assets or businesses. Short-term cash requirements, such as operating expenses, maintenance capital expenditures and quarterly distributions to partners, are expected to be funded from our operating cash flows. We expect to fund long-term cash requirements for expansion projects and acquisitions from several sources, including cash flows from operating activities, borrowings under the commercial paper program we established in April 2005 and our credit facilities, and the issuance of additional equity and debt securities. Our ability to complete future debt and equity offerings and the timing of any such offerings will depend on various factors, including prevailing market conditions, interest rates, our financial condition and credit rating at the time.

In April 2005, we entered into the third amendment to the Amended and Restated Credit Agreement dated as of January 24, 2003 (the “Credit Facility”) to, among other things, extend the maturity of the Credit Facility for a period of five years to April 2010; increase the letter of credit sublimit from $100 million to $175 million; and grant us the right to request, subject to approval by the Board of Directors of Enbridge Management, L.L.C. (“Enbridge Management”), an increase in commitments available under the Credit Facility up to an aggregate outstanding principal amount of $1 billion.

Also in April 2005, we successfully entered the commercial paper market with the establishment of our $600 million commercial paper program that is backstopped by our Credit Facility. We expect to reduce our short-term borrowing costs by accessing the commercial paper market primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions. We have repaid the entire amount previously outstanding under our Credit Facility from proceeds we obtained from issuing commercial paper under this program. Our Credit Facility remains undrawn and available to backstop our commercial paper program. Under the terms of our commercial paper program, we can issue commercial paper up to the $600 million limit of our Credit Facility, reduced by the balance of outstanding Letters of Credit. At June 30, 2005, we had $390.0 million of commercial paper outstanding at a weighted average interest rate of 3.23% and outstanding Letters of Credit totaling $121.2 million with availability under our commercial paper program of $88.8 million.

On February 11, 2005, we issued an additional 2,506,500 Class A common units at $49.875 per unit, which generated proceeds, net of offering expenses, of approximately $124.8 million. We used the proceeds from this offering to repay borrowings under our Credit Facility. Additionally, the General Partner contributed $2.7 million to us to maintain its 2% general partner interest in the Partnership.

Working capital, defined as current assets less current liabilities, decreased by $1.2 million to $68.3 million at June 30, 2005, compared with $69.5 million at December 31, 2004. This decrease was primarily attributable to general timing differences in the collection on and payment of our related party and current accounts.

At June 30, 2005, cash and cash equivalents totaled $82.4 million, compared with $78.3 million at December 31, 2004. Of the cash balance, $64.0 million ($0.925 per unit) is available for cash distributions to our unitholders on August 12, 2005. Of this distribution, $53.3 million will be paid in cash, $10.5 million will be distributed in i-units to our i-unitholder and $0.2 million retained from our General Partner in respect of this i-unit distribution.

Operating Activities

Net cash provided by operating activities for the six months ended June 30, 2005 was $123.7 million, compared with $154.1 million for the same period in 2004. The decrease in 2005 was primarily due to general timing differences in the collection on and payment of our related party and current accounts.

Investing Activities

Net cash used in investing activities during the six months ended June 30, 2005 was $357.6 million, compared with $199.7 million for the same period in 2004. The increase of $157.9 million was partially attributable to greater amounts we expended for the acquisition of the North Texas Gathering system and other natural gas gathering assets in 2005 than the amount we paid for the Mid-Continent and Palo Duro systems acquired in the first half of 2004. We acquired gathering and processing assets in north Texas for approximately $164.6 million in January 2005 and other natural gas gathering assets for approximately $21.3 million during the six months ended June 30, 2005. In addition to our acquisitions, we spent approximately $174.7 million in connection with our core maintenance and system enhancement projects, representing an increase of $103.9 million over the $70.8 million we spent in the first half of 2004, primarily due to the construction of our East Texas system expansion, which was completed in June 2005, and several smaller projects to expand our existing natural gas transmission and processing capacity as well as crude oil storage facilities. Additional information regarding our capital expenditures is provided below.

Financing Activities

Net cash provided by financing activities during the six months ended June 30, 2005 was $238.0 million, compared with $51.7 million for the corresponding period in 2004. The increase of $186.3 million in cash flow is primarily due to the proceeds we received from the additional Class A common units we issued in February 2005 and net borrowings under our commercial paper program and Credit Facility, partially offset by an increase in distributions to our partners. Distributions to our partners were higher in 2005 due to an increase in the number of units outstanding, as well as a related increase in the general partner incentive distributions resulting from the larger number of units outstanding.

CAPITAL EXPENDITURES

We rely upon cash flow from our operating activities and access to the capital markets to provide the funds necessary to execute our growth strategy and complete our projects. Our success with generating and raising capital is a critical factor that determines how much we actually spend. We believe our ability to generate or otherwise access the necessary capital resources is sufficient to meet the demands of our current and future operating growth needs. Although we currently intend to make the forecasted expenditures discussed below, we may adjust the timing and amounts of projected expenditures as necessary to adapt to changes in economic conditions.

We estimate our capital expenditures based on our long range strategic operating and growth plans. These estimates may change due to factors beyond our ability to control including changes in supplier prices, resource constraints, or poor economic conditions. Additionally, estimates may change as a result of decisions made at a later date, which may include acquisitions, scope changes or operational considerations.

We categorize capital expenditures as either core maintenance or system enhancement expenditures. Core maintenance expenditures are those expenditures that are necessary to maintain the service capability of our existing assets and include the replacement of system components and equipment which are worn, obsolete or approaching the end of their useful lives. Enhancement expenditures improve the service capability of our existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues and enable us to respond to governmental regulations and developing industry standards. We made capital expenditures of approximately $174.7 million, including $13.3 million on core maintenance activities, during the six months ended June 30, 2005. For the full year 2005, we anticipate capital expenditures to approximate $408 million, as illustrated in the following table below:

	(in millions)
System enhancements	$308
Core maintenance activities	43
East Texas expansion	57
	$408

As of June 30, 2005, we have contractual commitments totaling $19.2 million for materials and services related to our organic growth projects. We expect to settle these commitments during the remainder of 2005 and 2006.

We anticipate funding our capital expenditures temporarily through our Credit Facility or our commercial paper program, with permanent debt and equity funding being provided as appropriate. Core maintenance expenditures are expected to be funded by operating cash flows.

We expect to incur continuing annual capital and operating expenditures for pipeline integrity measures to both ensure regulatory compliance and to maintain the overall integrity of our pipeline systems. Expenditure levels have continued to increase as pipelines age and require higher levels of inspection or maintenance; however, these are viewed to be consistent with industry trends.

DERIVATIVE ACTIVITIES

We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the volatility of our cash flows and manage the purchase and sales prices of our commodities. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or anticipated transaction and are not entered into with the objective of speculating on commodity prices.

The following table provides information about the timing and expected settlement amounts of our outstanding commodity derivative financial instruments at June 30, 2005:

	Notional	2005	2006	2007	2008	2009	2010	2011	2012
				(in millions)					
Swaps									
Natural gas[1]	580,791,099	$ (9.9)	$(31.5)	$(27.7)	$(25.3)	$(21.2)	$(18.6)	$(17.7)	$(3.8)
NGL[2]	7,974,830	(12.2)	(10.2)	(9.7)	(3.4)	—	—	—	—
Crude[2]	1,192,509	(4.1)	(6.2)	(6.0)	(3.9)	(0.6)	—	—	—
Options—calls									
Natural gas[1]	7,125,000	(1.5)	(3.5)	(3.1)	(2.7)	(2.4)	(2.1)	(2.1)	—
Options—puts									
Natural gas[1]	7,585,000	—	—	—	—	—	—	—	—
Totals		$(27.7)	$(51.4)	$(46.5)	$(35.3)	$(24.2)	$(20.7)	$(19.8)	$(3.8)

(1) Notional amounts for natural gas are recorded in millions of British thermal units ("MMBtu").

(2) Notional amounts for NGL and Crude are recorded in Barrels ("Bbl").

OFF-BALANCE SHEET ARRANGEMENTS

We do not have any off-balance sheet arrangements.

SUBSEQUENT EVENTS

Distribution Declaration

On July 28, 2005, Enbridge Management's Board of Directors declared a distribution payable on August 12, 2005. The distribution will be paid to unitholders of record as of August 5, 2005, of our available cash of $64.0 million at June 30, 2005, or $0.925 per common unit. Of this distribution, $53.3 million will be paid in cash, $10.5 million will be distributed in i-units to our i-unitholder and $0.2 million will be retained from the General Partner in respect of this i-unit distribution.

FUTURE PROSPECTS

Liquids

Average daily crude oil deliveries on our Lakehead system are expected to decrease by approximately 20,000 Bpd during 2005 to approximately 1.38 million Bpd, from our previous forecast of 1.40 million Bpd. This also represents a year-over year decrease of approximately 42,000 Bpd, from 2004 deliveries of 1.422 million Bpd. The decrease is primarily attributable to the early January 2005 fire at the Suncor oil sands plant in Alberta, a major producer of crude oil in western Canada. Suncor expects to return to full production capacity in September 2005 which should result in a substantial increase in western Canadian crude oil supply and deliveries on our Lakehead system in the fourth quarter.

In June 2005, an Open Season was commenced by the Partnership and Enbridge Inc. ("Enbridge") to confirm shipper support for the Southern Access Mainline Expansion and Extension Program ("Southern Access Program"). The Mainline Expansion consists of up to three separate phases, which in aggregate is designed to provide an additional 400,000 Bpd of crude oil capacity on the Enbridge/Lakehead mainline system from Hardisty, Alberta to Chicago, Illinois. The U.S. portion of the Mainline Expansion program, from the international border to Chicago, will be undertaken on our Lakehead system at a cost of approximately $760 million, taking into consideration the expected savings of proceeding with all three phases concurrently. The Southern Access Extension will involve the construction of a new 30-inch diameter 300,000 Bpd pipeline from a new interconnection with our Lakehead system, near Chicago, to hubs at Wood River and/or Patoka, Illinois, at a total cost of approximately $320 million. The Southern Access Extension will be undertaken by a U.S. subsidiary of Enbridge and integrated with our Lakehead system for rate-making purposes. The Mainline Expansion can be accomplished either as one project or in phases. The Open Season was successfully concluded in late July 2005 with strong endorsement from shippers for Enbridge and the Partnership to proceed concurrently with all three phases of the Southern Access Program. As a result, we and Enbridge will proceed with negotiation of final contract terms with individual shippers, or the Canadian Association of Petroleum Producers on their behalf, as well as obtaining Canadian and U.S. regulatory approvals.

Enbridge and the Partnership are seeking industry input and support for the Southern Access Program through two parallel processes. First, with respect to the Mainline Expansion, we are seeking letters of support from shippers which will provide input on the number of phases they desire to trigger, as well as shipper support for the tolling methodologies for recovery of costs. The second process relates specifically to the Southern Access Extension and involves an open season conducted in two stages. During Stage I, prospective shippers are asked to submit non-binding expressions of interest, which will give an indication of the potential volumes of crude oil available for the Extension, as well as the preferred destination for the crude. If Enbridge decides to proceed to Stage II of the open season, prospective shippers will execute binding agreements providing volume commitments for the Extension. Assuming all necessary approvals and other contingencies are satisfied, and the Southern Access Program proceeds as a single project, it is anticipated that all phases could be in-service by the first quarter of 2009.

In June 2005, Enbridge acquired the remaining 10% stake in the Spearhead Pipeline, giving it 100% ownership in the pipeline, which runs from Cushing, Oklahoma to Chicago. After a successful open season in the fall of 2004, Enbridge is currently in the process of reversing the flow of the Spearhead Pipeline so that it will provide capacity to deliver 125,000 Bpd into the major oil hub at Cushing by 2006. This line could subsequently be expanded to accommodate up to 160,000 Bpd. The FERC approved the application for Spearhead transportation tariffs on March 3, 2005. A portion of the Spearhead Pipeline's revenue requirement will be rolled into Enbridge's Canadian mainline tariffs, which was approved in the second quarter of 2005 by Canada's National Energy Board ("NEB"). The NEB decision has been appealed by one intervener based on jurisdictional grounds and Enbridge is waiting for a response from Canada's Federal Court of Appeal on whether the appeal will be heard. Enbridge expects that this appeal will not be successful and therefore, is proceeding with the reversal project. We expect to benefit following the reversal, as western Canadian crude oil will be carried on the Lakehead system as far as Chicago, and then transferred to the Spearhead Pipeline to continue to this new market.

During 2004, ExxonMobil Pipeline Company ("ExxonMobil") approached the Canadian Association of Petroleum Producers and prospective shippers with a proposal to reverse the direction of flow on their Beaumont, Texas to Corsicana, Texas and their Corsicana, Texas to Patoka pipelines. The combined reversed pipeline will be linked to our Lakehead system at Chicago via the Mustang Pipe Line Partners system to Patoka. Mustang Pipe Line Partners system is 30% owned by an affiliate of Enbridge. ExxonMobil completed a successful open season with commitments of 50,000 Bpd, and have stated that they will proceed with the reversal, with plans to be in-service by the end of 2005. The reversed pipeline is expected to transport 65,000 Bpd of western Canadian heavy crude to the refinery market located in Beaumont on the U.S. Gulf Coast. The connection of the Lakehead system with this new market should also support increased throughput on the Lakehead system; however, the reversed system will also be capable of transporting western Canadian crude moved via other competing pipelines into Patoka.

Two proposals are currently being pursued to increase pipeline capacity for transportation of crude oil from the oil sands in Alberta to the west coast of Canada, where it could be shipped by tanker to China, other Asia-Pacific markets and California.

The Gateway Pipeline is a new 30-inch crude oil pipeline with design capacity of 400,000 Bpd. In April 2005, a memorandum of understanding was entered into between Enbridge and PetroChina International Company Limited to cooperate on the development of the Gateway Pipeline in order to supply approximately 200,000 Bpd of crude oil to China. A regulatory application for the $2.5 billion (Canadian dollars), 720-mile pipeline would have to be made in 2006 to achieve a late 2009-2010 in-service date, which is when Enbridge's western Canada crude oil supply forecast indicates that oil sands production will have increased to the level that access to a major new market will be beneficial to producers. Enbridge estimates that between 600,000 and 800,000 Bpd of incremental oil sands production will be available by 2010.

Terasen Inc.'s TMX project, is a proposed capacity expansion of their existing Trans Mountain Pipeline system, that runs from Alberta to British Columbia, Canada and Washington state. In July 2005, Terasen Inc. filed an application with the NEB to increase the capacity of their Trans Mountain pipeline system from 225,000 Bpd to 260,000 Bpd., with a planned in-service date of the first quarter of 2007.

These pipeline expansions are in line with the Partnership's expectations for increased access to new and existing markets for western Canadian crude oil. The Partnership expects the growing supply of crude oil from the Alberta oil sands to exceed the pipeline capacity to current and proposed markets which will require the development of new pipelines out of Western Canada.

Natural Gas

We continue to assess various acquisition and expansion opportunities to pursue our strategy for growth. The market for acquiring energy transportation assets is active and competition among prospective acquirers of assets has been significant. While we remain committed to making accretive acquisitions in or near areas where we already operate or have a competitive advantage, we will continue to focus our efforts on development of our existing pipeline systems. Although our primary objective is to grow our natural gas business through acquisitions, we may also pursue opportunities to divest of any non-strategic natural gas assets as conditions warrant.

We completed construction in June 2005 of our new 500 MMcf/d East Texas Expansion Pipeline Project. This new pipeline represents a strategic link between producers both in the Barnett Shale area of North Central Texas and the Bossier/Cotton Valley horizons in East Texas and new markets accessible through the pipeline hub at Carthage, Texas. Carthage access is important to natural gas shippers because it offers a number of pipeline connections which generally provide higher wellhead gas prices for producers. The pipeline is operating within its originally projected capacity with continued increases in utilization expected through the remainder of the year resulting from negotiation of additional commercial arrangements, organic supply growth, and other growth initiatives on our East Texas system.

In addition to the completion of the East Texas Expansion Pipeline Project, the Enbridge Management Board of Directors approved, and we initiated, a series of new projects to restart as well as construct certain treating and processing facilities on our East Texas system. We expect to complete these new projects in early 2006 at an estimated cost of approximately $75 million. Completion of these new projects will expand the service offerings we currently provide to our customers on the East Texas system.

Construction on our Anadarko system expansion continues. The first phase of the expansion added 100 MMcf/d of processing capacity at a cost of $38 million and entered service in April 2005. We are now proceeding with increasing the scale of that processing plant to 160 MMcf/d. The cost of this second phase is approximately $14 million and we expect it to be complete by the end of the fourth quarter of 2005.

Our Bamagas system has agreements to provide transportation of up to 276,000 MMBtu/d of natural gas for a remaining period of 17 years to two utility plants that are indirectly owned by Calpine Corporation ("Calpine"). The Bamagas system receives a fixed demand charge of $0.07 per MMBtu of natural gas for 200,000 MMBtu/d, regardless of whether the capacity is used. Calpine has recently experienced financial difficulties that it is actively working to alleviate. Although we fully expect our customer to remain solvent and its plants to meet their obligations to us under the terms of the transportation agreements, we are exposed to a potential asset impairment of up to $50 million, representing the book value of the pipeline, should they be unable to fulfill their commitments. We are actively monitoring Calpine's financial condition and evaluating alternate uses for the system.

REGULATORY MATTERS

FERC Transportation Tariffs-Liquids

Effective July 1, 2005, in compliance with the indexed rate ceilings allowed by the FERC, the Partnership increased its rates for transportation on the Lakehead, North Dakota and Ozark systems by an average of approximately 3.63%. For the Lakehead system, indexing only applies to its base rates, not the surcharges for SEP II, Terrace and Facilities. The Partnership anticipates that the increase in tariff rates will not have a material impact on the Partnership's financial condition and results of operations. On the Lakehead system, the new rate for heavy crude movements from the International Border to Chicago is $0.89 per barrel, which reflects an approximate 2.5 cents per barrel increase over rates filed effective April 1, 2005.

Effective April 1, 2005, Enbridge Energy, Limited Partnership ("Lakehead Partnership"), a subsidiary of the Partnership, filed a new tariff with the FERC. This new tariff reflects the annual calculation of the SEP II and Facilities surcharges based on true-ups of prior year amounts and estimates for 2005, and an adjustment for the Terrace surcharge as a result of lower than expected volumes moving on the Lakehead system. This filing increased the tariff for heavy crude oil movements from the Canadian border to Chicago, Illinois, by approximately $0.035 per barrel, to approximately $0.865 per barrel.

FERC Policy on Income Tax Allowances

On May 4, 2005, the FERC adopted a policy to permit cost-of-service rates to reflect actual or potential income tax liability for all public utility assets, regardless of the form of ownership. The policy statement stems from an opinion issued by the U.S. Court of Appeals for the District of Columbia Circuit in *BP West Coast Products, LLC v. FERC* that remanded the FERC's decisions on tax allowance treatment in an oil pipeline rate proceeding involving SFPP, L.P., an unrelated pipeline company.

Under the policy, all entities or individuals owning public utility assets would be permitted an income tax allowance on the income from those assets, provided that they have an actual or potential income tax liability on that public utility income. As a result, a taxpaying corporation, partnership, limited liability corporation, or other pass-through entity would be permitted an income tax allowance on the income imputed to the corporation, or to the partners or the members of pass-through entities. Any pass-through entity seeking an income tax allowance in a specific rate proceeding will be required to establish that its partners or members have an actual or potential income tax obligation on the entity's public utility income. Management is evaluating the new FERC policy. At this time we do not believe the adoption of this policy by the FERC will have a material effect on our financial position, results of operations or cash flows.

FERC Guidance on Accounting for Integrity Management Costs

In June 2005, the FERC issued guidance describing how FERC-regulated companies should account for costs associated with implementing the pipeline integrity management requirements of the U.S. Department of Transportation's Office of Pipeline Safety. Under the guidance, costs to 1) prepare a plan to implement the program, 2) identify high consequence areas, 3) develop and maintain a record keeping system and 4) inspect, test and report on the condition of affected pipeline segments to determine the need for repairs or replacements, are required to be expensed. Costs of modifying pipelines to permit in-line inspections, certain costs associated with developing or enhancing computer software and costs associated with remedial and mitigation actions to correct an identified condition can be capitalized. The guidance is effective January 1, 2006, to be applied prospectively. We are currently evaluating the effect that application of this order will have on our financial statements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

This information updates, and you should read it in conjunction with, our quantitative and qualitative disclosures about market risks reported in our Annual Report on Form 10-K, as amended, for the year ended December 31, 2004, in addition to information presented in Items 1 and 2 of this Quarterly Report on Form 10-Q.

Our net income and cash flows are subject to volatility stemming from changes in commodity prices of natural gas, NGLs, condensate and fractionation margins (the relative price differential between NGL sales and offsetting natural gas purchases). This market price exposure exists within our Natural Gas and Marketing segments. To mitigate the volatility of our cash flows, we use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the purchase and sales prices of the commodities. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or anticipated transaction and are not entered into with the objective of speculating on commodity prices.

The following tables provide information about our derivative financial instruments at June 30, 2005 and December 31, 2004, with respect to our commodity price risk management activities for natural gas and NGLs, including crude:

	At June 30, 2005						At December 31, 2004	
			Wtd Avg Price[2]		Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Receive	Pay	Asset	Liability	Asset	Liability
Contracts maturing in 2005								
Swaps								
Receive variable /pay fixed	Natural Gas	91,953,108	$ 7.11	$ 6.51	$ 57.2	$ (2.7)	$ 8.1	$(54.5)
Receive fixed /pay variable	Natural Gas	90,713,493	6.51	7.23	3.3	(67.5)	48.3	(25.9)
	NGL	2,043,412	27.26	33.28	—	(12.2)	1.0	(8.0)
	Crude	173,880	34.41	58.44	—	(4.1)	—	(3.2)
Receive variable /pay variable	Natural Gas	16,962,369	6.90	6.92	0.2	(0.4)	0.7	(2.4)
Options								
Calls (written)	Natural Gas	552,000	7.38	4.74	—	(1.5)	—	(1.7)
Puts	Natural Gas	1,012,000	7.37	4.13	—	—	0.1	—
Contracts maturing in 2006								
Swaps								
Receive variable /pay fixed	Natural Gas	124,253,066	7.72	6.83	108.0	(0.2)	4.2	(7.8)
Receive fixed /pay variable	Natural Gas	127,700,926	6.72	7.85	0.2	(139.1)	7.8	(23.3)
	NGL	2,602,815	28.59	32.69	0.5	(10.7)	0.5	(4.1)
	Crude	342,900	39.87	58.86	—	(6.2)	0.4	(1.4)
Receive variable /pay variable	Natural Gas	1,887,781	7.80	8.00	—	(0.4)	—	(0.2)
Options								
Calls (written)	Natural Gas	1,095,000	7.99	4.74	—	(3.5)	—	(1.8)
Puts	Natural Gas	1,095,000	7.99	3.40	—	—	—	—
Contracts maturing in 2007								
Swaps								
Receive variable /pay fixed	Natural Gas	37,782,671	7.50	6.87	22.3	(0.3)	0.6	(8.2)
Receive fixed /pay variable	Natural Gas	41,914,481	6.44	7.72	0.9	(50.6)	8.5	(15.8)
	NGL	2,599,165	27.62	31.66	0.9	(10.6)	0.4	(4.0)
	Crude	306,555	36.41	57.82	—	(6.0)	0.2	(1.3)
Receive variable /pay variable	Natural Gas	214,000	7.15	7.27	—	—	—	—
Options								
Calls (written)	Natural Gas	1,095,000	7.75	4.74	—	(3.1)	—	(1.5)
Puts	Natural Gas	1,095,000	7.75	3.40	—	—	—	—

	At June 30, 2005						At December 31, 2004	
			Wtd Avg Price[2]		Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Receive	Pay	Asset	Liability	Asset	Liability
Contracts maturing in 2008								
Swaps								
Receive variable /pay fixed	Natural Gas	8,047,000	7.47	7.00	3.4	—	—	(1.9)
Receive fixed	Natural Gas	16,262,000	5.50	7.48	0.6	(29.3)	2.3	(12.2)
/pay variable	NGL	729,438	25.59	30.93	—	(3.4)	0.7	(0.2)
	Crude	268,799	40.72	57.01	—	(3.9)	0.5	—
Options								
Calls (written)	Natural Gas	1,098,000	7.37	4.74	—	(2.7)	—	(1.2)
Puts	Natural Gas	1,098,000	7.37	3.40	—	—	0.1	—
Contracts maturing in 2009								
Swaps								
Receive fixed	Natural Gas	7,300,000	3.63	7.05	—	(21.2)	—	(9.8)
/pay variable	Crude	100,375	49.43	56.45	—	(0.6)	—	—
Options								
Calls (written)	Natural Gas	1,095,000	7.05	4.74	—	(2.4)	—	(1.1)
Puts	Natural Gas	1,095,000	7.05	3.40	—	—	0.2	—
Contracts maturing after 2009								
Swaps								
Receive fixed /pay variable	Natural Gas	15,796,500	3.63	6.85	—	(40.0)	—	(18.3)
Options								
Calls (written)	Natural Gas	2,190,000	6.79	4.74	—	(4.0)	—	(2.0)
Puts	Natural Gas	2,190,000	6.79	3.40	$ 0.1	—	0.5	—

(1) Volumes of Natural gas are measured in MMBtu, whereas NGL and Crude are measured in Bbl.

(2) Weighted average prices received and paid for Natural gas are in $/MMBtu and in $/Bbl for NGL and Crude.

(3) The fair value is determined based on quoted market prices at June 30, 2005 and December 31, 2004, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars.

Accounting Treatment

All derivative financial instruments are recorded in the consolidated financial statements at fair market value and are adjusted each period for changes in the fair market value ("mark-to-market"). Under the guidance of SFAS No. 133, changes in the fair market value of derivatives that qualify as highly effective cash flow hedges are recorded as components of Accumulated other comprehensive loss until the hedged transactions occur ("hedge accounting"). Hedge accounting can apply to either a hedge of future cash flows or the fair value of an asset or liability. Any ineffective portion of a cash flow hedge's change in fair value is recognized each period in earnings. When the hedged transaction occurs, the fair value of the derivative is recognized in earnings, along with the offsetting fair value of the physical transaction. For those derivative financial instruments that do not qualify for cash flow hedge accounting, the total change in fair value is recorded directly in earnings each period. Our preference, whenever possible, is for our derivative financial instruments to receive hedge accounting treatment in order to mitigate the noncash earnings volatility that arises under mark-to-market accounting treatment. However, to qualify for cash flow hedge accounting, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

Non-Qualified Hedges

Many of our derivative financial instruments qualify for hedge accounting treatment under the specific requirements of SFAS No. 133. However, we have three primary instances where the hedge structure does not meet the requirements to apply hedge accounting and therefore, these financial instruments are considered 'non-qualified' under SFAS No. 133. In these instances, the impacts of mark-to-market accounting for our non-qualified hedges are recorded in our Consolidated Statements of Income. These non-qualified derivative financial instruments must be adjusted to their fair market value, or marked-to-market, each period, with the increases and decreases in fair value recorded as increases and decreases in Cost of natural gas on our Consolidated Statements of Income. These mark-to-market adjustments produce a degree of earnings volatility that can often be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the underlying physical transaction takes place in the future and an associated financial instrument contract settlement is made.

The three instances of non-qualified hedges are as follows:

1. In our Marketing segment, when the pricing index used for gas sales is different from the pricing index used for gas purchases, we are exposed to relative changes in those two indices. By entering into a basis swap between those two indices, we can effectively lock in the margin on the combined gas purchase and gas sale, removing any market price risk on the physical transactions. Although this represents a sound economic hedging strategy, these types of derivative transactions do not qualify for hedge accounting under SFAS No. 133, as the ultimate cash flow has not been fixed, only the margin.

2. In our Marketing segment, when we use derivative financial instruments to hedge market spreads around our owned or contracted assets, such as our gas storage portfolio, the underlying forecasted transaction may or may not occur in the same period as originally forecast. This can occur as we have the flexibility to make these changes in the underlying injection or withdrawal schedule, given changes in market conditions. Therefore, these transactions do not qualify for hedge accounting treatment under SFAS No. 133, as the forecasted transaction is no longer probable of occurring as originally set forth in the hedge documentation.

3. In our Natural Gas segment, we had previously entered into natural gas collars in order to hedge the sales price of natural gas. The natural gas collars were based on a NYMEX price while the physical gas sales were based on a different index. To better align the index of the natural gas collars with the index of the underlying sales, we de-designated the original hedging relationship and contemporaneously re-designated the natural gas collars as hedges of physical natural gas sales with a NYMEX pricing index to better match the indices. This is a sound economic hedging strategy, however, since these instruments were out of the money at re-designation, they are considered net written options under SFAS No. 133. Therefore, these instruments do not qualify for hedge accounting upon re-designation and are now accounted for in the Consolidated Statements of Income through mark-to-market accounting, with their changes in fair value from the date of de-designation recorded to earnings each period. As a result, our operating income

will be subject to greater volatility due to movements in the prices of natural gas until these underlying long-term transactions are settled.

Discontinuance of Hedge Accounting

During the second quarter of 2005, we discontinued application of hedge accounting in connection with some of our derivative financial instruments designated as hedges of forecasted sales and purchases of natural gas. We discontinued application of hedge accounting when we determined it was no longer probable that the originally forecasted purchases and sales of natural gas would occur by the end of the originally specified time period, or within an additional two-month period of time thereafter. One of the key criteria to achieve hedge accounting under SFAS No. 133, is that the forecasted transaction is probable of occurring as originally documented in the hedge documentation. As a result, we recognized previously deferred unrealized losses in our Marketing segment of approximately $9.0 million from the discontinuance of hedge accounting. In doing so, we reclassified the $9.0 million to Cost of natural gas on our Consolidated Statements of income from Accumulated other comprehensive income. Going forward, the discontinued derivative financial instruments are considered to be non-qualified under SFAS No. 133, and must now be marked-to-market each period, with the increases and decreases in fair value recorded as increases and decreases in earnings. Included in the loss from discontinuance are approximately $2.1 million of net mark-to-market losses that relate to hedge positions that were closed-out during the second quarter.

The following table presents the gains and losses associated with changes in the fair value of our derivatives which are recorded as an element of Cost of natural gas in our Consolidated Statements of Income and disclosed as a reconciling item on our Statements of Cash Flows:

Derivative fair value gains (losses)	Three months ended June 30, 2005	Three months ended June 30, 2004	Six months ended June 30, 2005	Six months ended June 30, 2004
	(in millions)			
Natural Gas segment				
Ineffectiveness	$(1.8)	$ —	$ (2.0)	$ —
Non-qualified hedges	(2.9)	—	(11.1)	—
Marketing				
Non-qualified hedges	3.9	(1.9)	5.3	(1.7)
Discontinuance	(9.0)	—	(9.0)	—
Derivative fair value loss	$(9.8)	$(1.9)	$(16.8)	$(1.7)

We record the change in fair value of our highly effective cash flow hedges in our Consolidated Statements of Comprehensive Income until the derivative financial instruments are settled, at which time they are reclassified to earnings. For the three and six months ended June 30, 2005, we reclassified unrealized losses of $9.4 million and $25.2 million, from Accumulated other comprehensive loss to Cost of natural gas on our Consolidated Statements of Income for the fair value of derivative financial instruments that were settled.

Our derivative financial instruments are included at their fair values in the Consolidated Statements of Financial Position as follows:

	June 30, 2005	December 31, 2004
	(in millions)	
Receivables, trade and other	$ 5.3	$ 8.2
Other assets, net	9.4	10.1
Accounts payable and other	(60.8)	(45.9)
Deferred credits	(182.5)	(99.6)
	$(228.6)	$(127.2)

The increase in our obligation associated with our derivative activities from December 31, 2004 to June 30, 2005 is primarily due to the significant increases in forward natural gas and NGL prices. The Partnership's portfolio of derivative financial instruments is largely comprised of long-term fixed price sales agreements.

We do not require collateral or other security from the counterparties to our derivative financial instruments. All of our counterparties were rated "A" or better by all major credit rating agencies.

Item 4. Controls and Procedures

The Partnership and Enbridge maintain systems of disclosure controls and procedures designed to provide reasonable assurance that we are able to record, process, summarize and report the information required in our annual and quarterly reports under the Securities Exchange Act of 1934. Our management has evaluated the effectiveness of our disclosure controls and procedures as of June 30, 2005. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures are effective to accomplish their purpose. In conducting this assessment, our management relied on similar evaluations conducted by employees of Enbridge affiliates who provide certain treasury, accounting and other services on our behalf. No changes in our internal control over financial reporting were made during the three months ended June 30, 2005, that would materially affect our internal control over financial reporting, nor were any corrective actions with respect to significant deficiencies or material weaknesses necessary subsequent to that date.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

Refer to Part I, Item 1. Financial statements, Note 7, which is incorporated herein by reference.

Item 6. Exhibits

Each exhibit identified below is filed as part of this document. Exhibits not incorporated by reference to a prior filing are designated by an "*"; all exhibits not so designated are incorporated herein by reference to a previous filing as indicated.

3.1	Certificate of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.1 to the Partnership's Registration Statement No. 33-43425).
3.2	Certificate of Amendment to Certificate of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.2 to the Partnership's 2000 Form 10-K/A dated October 9, 2001).
3.3	Third Amended and Restated Agreement of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.1 to the Partnership's Quarterly Report on Form 10-Q filed November 14, 2002).
4.1	Form of Certificate representing Class A Common Units (incorporated by reference to Exhibit 4.1 to the Partnership's 2000 Form 10-K/A dated October 9, 2001).
10.1	Third Amendment to the Amended and Restated Credit Agreement, dated as of January 24, 2003 (as amended by the First Amendment, dated January 12, 2004 and the Second Amendment, dated as of April 26, 2004), by and among the Partnership, the lenders from time to time parties thereto, and Bank of America, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K filed on April 19, 2005).
10.2	Commercial Paper Dealer Agreement between the Company, as Issuer, and Banc of America Securities LLC, as Dealer, dated as of April 21, 2005 (incorporated by reference to exhibit 10.1 to the Partnership's Current Report on Form 8-K filed May 3, 2005).
10.3	Commercial Paper Dealer Agreement between the Company, as Issuer, and Deutsche Bank Securities Inc., as Dealer, dated as of April 21, 2005 (incorporated by reference to exhibit 10.2 to the Partnership's Current Report on Form 8-K filed May 3, 2005).
10.4	Commercial Paper Dealer Agreement between the Company, as Issuer, and Goldman, Sachs & Co., as Dealer, dated as of April 21, 2005 (incorporated by reference to exhibit 10.3 to the Partnership's Current Report on Form 8-K filed May 3, 2005).
10.5	Commercial Paper Dealer Agreement between the Company, as Issuer, and Merrill Lynch Money Markets Inc., as Dealer, dated as of April 21, 2005 (incorporated by reference to exhibit 10.4 to the Partnership's Current Report on Form 8-K filed May 3, 2005).
10.6	Issuing and Paying Agency Agreement between the Company and Deutsche Bank Trust Company Americas, dated as of April 21, 2005 (incorporated by reference to exhibit 10.5 to the Partnership's Current Report on Form 8-K filed May 3, 2005).
31.1*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

ENBRIDGE ENERGY PARTNERS, L.P.
(Registrant)

By: Enbridge Energy Management, L.L.C.
as delegate of
Enbridge Energy Company, Inc.
as General Partner

Date: August 5, 2005

By: /s/ DAN C. TUTCHER
Dan C. Tutcher
President and Director
(Principal Executive Officer)

Date August 5, 2005

By: /s/ MARK A. MAKI
Mark A. Maki
Vice President, Finance
(Principal Financial Officer)